BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering.	R.20-08-020 (Filed August 27, 2020)

JOINT OPENING COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), PACIFIC GAS AND ELECTRIC COMPANY (U 39-E) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E) ON THE NEW PROPOSED DECISION OF ALJ HYMES REVISING NET ENERGY METERING TARIFF AND SUBTARIFFS

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SUBJECT INDEX OF RECOMMENDED CHANGES

Pursuant to Rule 14.3(b) of the California Public Utilities Commission's (Commission) Rules of Practice and Procedure, Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) (collectively, the "Joint Utilities") provide the following Subject Index of Recommended Changes in support of their Joint Opening Comments to the November 10, 2022 Proposed Decision (PD) Revising Net Energy Metering Tariff and Subtariffs. Specifically, the final decision should:

1. Correct the following legal errors:
    a. To meet the cost-benefit mandates set forth in Assembly Bill (AB) 327;
    b. Assess all non-bypassable charges (NBCs) on net billing tariff (NBT) customers absent a statutory exemption and do so on the same basis as other customer generators;
    c. Specify that the allowance for systems oversized by 50 percent: (i) is based on the customer's prior year's usage; and (ii) is secondary to the requirement that customers must expect to increase their usage accordingly in the next year and so attest;
    d. Clarify that the ACC-plus adder is not applicable to net surplus generation.
2. Adopt a mechanism to recover infrastructure and policy costs; otherwise, provide explicit direction to do so in the Demand Flexibility OIR (R.22-07-005).
    a. The record demonstrates a cost shift from customers avoiding infrastructure and policy costs due to volumetric rate design and the urgent need for reform;
    b. Solar parties have provided statements on the record in other proceedings opposing mandatory or sufficient recovery of infrastructure and policy costs;
    c. If not here, the final decision should direct that the Demand Flexibility OIR should adopt a mandatory fixed charge for these customers that recovers their fair share of infrastructure and policy costs.
3. Require NEM 1.0 and 2.0 customers to transition to a tariff without a subsidy at the end of their legacy period.
    a. The PD would create a perpetual subsidy for NEM 1.0 and 2.0 customers;
    b. The PD should direct a tariff that eliminates or at least minimizes the subsidy for these customers here; otherwise, the final decision should direct a no subsidy tariff be adopted in the Demand Flex OIR Track B;
4. Ensure that the NEM and NBT subsidies are transparent going forward

a. The cost shift should be calculated annually and submitted to the CPUC and Legislature;

b. Consider whether to provide as a bill insert or other mechanism for customers.

5. Fix modeling errors that lead to unnecessary additional solar subsidies (i.e., ACC-plus).

   a. The model assumptions of system size and cost of solar are flawed;

   b. The simple payback methodology does not include a rate escalation, which is inconsistent with how solar panels are marketed to customers.

6. Simplify the virtual net billing and load aggregation tariffs because they are unnecessarily complex and expensive to implement.

7. Clarify various technical, implementation, and timing issues:

   a. Adopt changes to timing of some advice letters without changing the overall schedule;

   b. Clarify cost recovery;

   c. Eliminate the requirement that the Joint Utilities notify customers when customer generating systems are not working;

   d. Eliminate the requirement that the Joint Utilities provide 15-minute interval data;

   e. Clarify the nine-year lock-in eligibility for the export compensation rate and ACC plus adder;

   f. Grant PG&E a phased implementation and allow it to bill NBT customers temporarily taking service on NEM 2.0 on rates available to NEM 2.0 customers until the E-ELEC rate is available for NEM customer enrollment;

   g. All the Joint Utilities to pause NEM 1.0 transitions to NEM 2.0 as soon as practicable (including before the NEM 2.0 sunset date) to avoid two transitions in quick succession;

   h. Requiring NEM 2.0 applications submitted before the sunset date to be subject to a completion timeline and authorizing the utilities discretion to grant NEM 2.0 eligibility to projects that fail to submit a complete application by the NEM 2.0 sunset date due to utility-caused delays; and

   i. Other minor clarifications and corrections.

These recommended changes are discussed in detail in these Opening Comments and modifications are set forth in **Attachment A**.

I. INTRODUCTION

Pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and the November 10, 2022 ALJ's proposed decision ("PD") revising Net Energy Metering tariff and subtariffs, Joint Utilities[1] submit these opening comments.[2] The Joint Utilities appreciate the continued and significant work that the Commission has undertaken in preparing the PD. The PD's findings of fact that California's current NEM program is not cost effective are overwhelmingly supported by the record. The PD begins to move in the right direction by reducing export compensation for new solar adopters, but it continues to maintain substantial subsidies and therefore continues cost-shifting to non-participants who are predominantly low-income customers. Unfortunately, this means that AB 327's directives are not met. The PD should be modified to address the legal, factual, and technical/implementation issues discussed below, and as set forth in **Attachment A** hereto.

II. THE PD SHOULD BE MODIFIED TO CORRECT LEGAL AND FACTUAL ERRORS

A. The PD's Nine-Year Payback Unlawfully Defies AB 327's Directives

AB 327 mandates that the Commission ensure that the benefits and costs of the successor NEM tariff are equalized.[3] When AB 327 was enacted in 2013, the NEM subsidy provided NEM customers, on average, with eight to 12-year paybacks.[4] The PD's nine-year payback returns the state to 2013. A comparison of the Lookback Study's cost-effectiveness analysis with the PD's analysis of the proposed net billing tariff (NBT), highlights that the PD barely moves the needle in addressing current inequalities.[5] The PD's own modeling shows that the NBT maintains a significant cost shift and all but guarantees that there will be a multi-billion dollar cost shift to non-participants indefinitely.[6] This outcome is insufficient for policy reasons and contrary to law.

B. The PD Errs in Allowing New Successor NEM Customers to Avoid NBCs

The PD errs in resolving two issues regarding NBC cost recovery from successor NEM customers: 1) whether NBCs should be recovered on "net" or "gross" consumption, and 2) whether to expand the list of NBCs that cannot be offset with bill credits from exported energy.[7] The PD

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1 Hereinafter, acronyms will either have the meaning assigned in the PD, these Comments' Summary of Recommendations, or Appendix A to the Joint Utilities Opening Brief (filed August 31, 2021).

2 Pursuant to Rule 1.8(d) of the Commission's Rules of Practice and Procedure, SCE and SDG&E have authorized PG&E to file and sign these comments on their behalf.

3 The Commission has recognized, "AB 327 addresses the cost shift." Decision (D.)21-02-007, p. 39, Finding of Fact (FOF) 32.

4 D.14-03-041, p. 35, FOF 2.

5 Compare Verdant Associates, "Net Energy Metering 2.0 Lookback Study," (Jan. 21, 2021) ("Lookback Study"), p. 5, Table 1-2 and PD, Appendix B, p. B-5.

6 PD, Appendix B, p. B-5.

7 *See* PD, p. 113.

reaches its findings and conclusions on NBC cost recovery ***without any legal analysis***, despite that NBC non-bypassability to avoid cost shifting is a longstanding, legal requirement in California law.

As to the first issue, the PD declines to require recovery of NBCs from NBT customers on gross consumption. In doing so, the PD ignores the record when stating – incorrectly – that "[a]ssessing [NBCs] on imported energy is consistent with the manner in which all customers currently pay for these costs."[8] Absent statutory exemptions, all customer generators (other than NEM customers) pay NBCs on the load they serve with their own, behind-the-meter generation (*i.e.*, on customer generation departing load) as well as the load they import from the grid. Thus, customer generators other than NEM today pay NBCs on gross consumption.[9] NBT customers have no statutory exemption from NBC costs; AB 327 eliminated the exemption from NBC cost recovery and directed the Commission to treat new successor NEM customers as "customer generators."[10] The PD ignores AB 327's requirements and commits legal and factual error in failing to assess NBCs on the same basis as all other customer generators (*i.e.,* on gross consumption).

As to the second issue, the PD declines to assess the NBCs enacted in law since 2016 on the imported energy of NBT customers. The PD perilously disregards new statutory NBCs:

> TURN, in addition to CalWEA, CUE, IEPA, NRDC, and Cal Advocates recommend the list of [NBCs] that cannot be offset on bills should be expanded…. TURN argues the Commission should expand the list of [NBCs] to include all current [NBCs], as they have been deemed non-bypassable by statute, and were not in existence at the time that NEM 2.0 was adopted. **Other than the statement that these are non-bypassable by statute, TURN offers no other justification for including the new charges**. This decision maintains the four charges adopted in D.16-01-044….[11]

The Commission cannot credibly disregard NBCs enacted since 2016, delineated in Table 5 of the PD,[12] in assessing cost responsibility for NBT customers. The Legislature did not authorize

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8 PD, p. 116. *See* Joint Utilities' Reply Comments (July 1, 2022), p. 7 ("Section 2827.1(b)(7) is hardly surprising given that customer generation is, by definition, departing load…. As a matter of law, departing load customers must pay NBCs unless that customer generator is expressly exempted by statute. …. ***In the absence of any statutory exemption, as is the case here, load served by an eligible renewable generating facility under the successor tariff must be treated as departing load and thus assessed NBCs in a nondiscriminatory fashion, i.e., on the same basis as all other customer generators, which for most NBCs is based on gross consumption***.") (Emphasis added, footnotes omitted).

9 *Id*.

10 *See* AB 327, *codified at* Pub. Util. Code § 2827.1(b)(7) ("The commission shall determine which rates and tariffs are applicable to **customer generators** only during a rulemaking proceeding. …The commission shall ensure **customer generators** are provided electric service at rates that are just and reasonable.") (emphasis added).

11 PD, pp. 116-17.

12 *See id*., pp, 115-16. For example, Pub. Util. Code §§ 850 – 850.8 (2020), enacted by Senate Bill (SB) 901, AB 1054 and AB 1513, enact the non-bypassable Fixed Recovery Charge (FRC). Section 850(a)(2) empowers the Commission to issue a financing order to authorize the recovery, through a "Fixed

the Commission to cherry-pick which NBCs to enforce for NBT customers or to redefine NBCs as other than what the Commission has long understood "non-bypassable" to mean: "cannot be discounted."[13] Yet, the PD does so by embracing the recently enacted Department of Water Resources (DWR) Wildfire Fund Charge as an NBC that cannot by bypassed and rejecting all other newly enacted statutory NBCs for this same treatment. The PD is wrong that the DWR Bond Charge was simply "renamed" the Wildfire Fund Charge.[14] They are two separate, statutory NBCs for DWR cost recovery. The PD commits legal and factual error in failing to assess all statutory NBCs enacted since 2016 in the same manner it assesses those NBCs identified in D.16-01-044.

C. Oversizing In Support of Electrification Policy Must Comply with the Law

To support electrification, the PD would adopt SEIA/Vote Solar's proposal to allow customers to oversize their systems by 50 percent.[15] The Joint Utilities support electrification policy, but as detailed in the Joint Utilities previous filings, oversizing is not merely a matter of policy; it implicates federal and state law by which the Commission must abide.[16] Allowing customers to oversize their systems by 50 percent runs afoul of these laws. If the Commission nonetheless allows oversized customer generators, the PD should be clarified to specify that its allowance for systems oversized by 50 percent: (i) is based on the customer's prior year's usage; and (ii) is secondary to the requirement that customers must expect to increase their usage accordingly in the next year and so attest. The Commission should also consider performing an audit to determine if attestations are made in good faith and for consumer protection reasons.

D. ACC-Plus Must Comply With The Law Governing Net Surplus Compensation (NSC)

The PD finds a glide path is necessary to allow for sustainable market growth.[17] The PD's glide path, the ACC Plus (ACC+) adder, would provide a fixed cents per kilowatt-hour adder on top

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Recovery Charge," of "costs and expenses related to catastrophic wildfires," that the Commission has determined to be just and reasonable, "including fire risk mitigation capital expenditures identified in subdivision (e) of Section 8386.3." Pub. Util. Code §§ 850(b)(7) and 850.1(b) provide that the FRC shall be nonbypassable and recovered from existing and future consumers in the IOU service area **other than CARE and FERA customers**. **If the Legislature intended to exempt this charge for NBT customers, it would have said so.** *See also* D.20-11-007 and D.21-10-025, issued for SCE pursuant to the new statute authorizing securitization, which make abundantly clear that, in accordance with the plain language in the statute, the FRC is non-bypassable, except with respect to CARE and FERA customers.

13 *See* Joint Utilities' Reply Comments (July 1, 2022), p. 7, footnote (fn.) 33 quoting D.07-09-016.

14 *See* PD, p. 116.

15 PD, pp. 91-93.

16 *See* Joint Utilities Opening Brief (Aug. 31, 2021), pp. 6-14; Joint Utilities' Opening Comments to the December 13, 2021 PD (Jan. 7, 2022), pp. 8-9.

17 PD, p. 85, *quoting* E3 White Paper executive summary.

of the ACC-based export credits.[18] While the PD disclaims intent to create a "double payment" for NSC at the annual true-up, it is not clear whether the PD would also apply the ACC+ adder to net exports receiving NSC.[19] To apply the adder to NSC would violate state and federal law.

As the PD accurately notes, net exports over the 12-month netting period determine whether a customer has triggered federal jurisdiction.[20] The PD further correctly explains: "if a net sale over the netting period occurs, the Public Utility Regulatory Policies Act of 1978 (PURPA) applies, prescribing the price paid for a net sale from a state net metering program."[21] The Commission has determined that price is the Default Load Aggregation Point (DLAP) price, which the PD expressly declines to revise.[22] The Commission, therefore, cannot lawfully include the adder on NSC. The final decision should clarify that the ACC+, which was paid to customers on net surplus generation, should be debited from the customer at the true up.

III. NECESSARY CLARIFICATIONS AND FACTUAL CORRECTIONS TO THE PD

A. The Commission Should Provide Clear Guidance for the Demand Flexibility OIR

In declining to adopt fixed or capacity-based charges and allowing a significant amount of cross subsidy to remain, the proposed decision assumes R.22-07-005 will create a rate structure to collect fixed costs from all customers, including customers on the NBT.[23] Solar parties have taken inconsistent positions on fixed charges: while they have repeatedly supported the notion of fixed charges on all customers (and to defer consideration of fixed charges in this proceeding), they also have clearly signaled that they intend to oppose any additional fixed charges in R.22-07-005. Solar parties have asserted on record that the fixed charge should be optional for NEM customers and lower than the actual amount required to fully recover fixed costs. In their post-prehearing conference comments in R.22-07-005, SEIA argued that the income-based fixed charge should not apply to all rates (including the rates the PD adopts as mandatory for NBT customers), effectively making the income-based fixed charge structure optional and nullifying the legislative directive to

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18 PD, p. 142.

19 *See* PD, pp. 155-156.

20 PD, p. 130 and fn. 370, *citing*, *Sun Edison LLC*, 129 FERC ¶ 61,146, 61620 (2009) (under federal law a net sale occurs where a net energy metering customer produces more energy than the customer needs "over the applicable billing period").

21 PD, p. 6.

22 PD, p. 93-94. "This decision makes no changes to the calculation of Net Surplus Compensation established by D.11-06-016" (PD at 155). *See*, D.11-06-016, pp. 62-63, Conclusions of Law (COL) 1, 4-7, 10 (to comply Commission's obligations under PURPA, *the NSC rate may not exceed avoided costs*, which the Commission set as the CAISO wholesale hourly day-ahead market price known as the Default Load Aggregation Point (DLAP) price, which reflects the cost the utility avoids in procuring power when net surplus generators are likely to produce excess power) (emphasis added).

23 PD, pp. 112, 125, 184, and p. 201, FOF 114-117.

have income-based fixed charges. Contradicting their previous prehearing conference comments, solar parties stated that fixed charges should apply to all residential customers and would support addressing this in R.22-07-005. The Final Decision should clarify that rooftop solar customers are required to take service on a rate including a fixed charge that fully recovers the cost of their use of the grid and their fair share of policy costs and NBCs.

B. NEM 1.0/2.0 Customers Should Transition to a Non-Subsidized Tariff at the End of Their Legacy Periods

The PD errs factually by allowing NEM 1.0/2.0 customers to transition to the subsidized NBT after their 20-year legacy period ends, despite acknowledging: "NEM 2.0 is not cost effective, has negatively impacted non-participant ratepayers, and has disproportionately harmed low-income customers."[24] A new NEM 2.0 customer today will enjoy a payback period of less than three years in SDG&E's service area and will continue to reap benefits for the entire 20-year legacy period. Because the NBT maintains a significant portion of the embedded subsidy, NEM customers transitioning to NBT will continue to enjoy a substantial subsidy after their generous 20-year legacy period ends. The Commission should require NEM customers to transition to a tariff that shifts no cost to non-participants once their legacy period ends so that non-participants do not continue to be burdened by the costs to subsidize these customers.

When declining to change NEM 1.0/2.0 requirements or legacy periods, the PD states that fixed charges will be considered in R.22-07-005,[25] implying that NEM cost shifting will be rectified there. While CALSSA stated it would support residential fixed charges in R.22-07-005, SEIA stated "We do have fixed charges," referring to the current "electrification" rates with fixed charges ranging from $12-16 that do not fully reflect actual fixed costs and do little to reduce the cost shift.[26] Without additional income-based fixed charges for NEM and NBT customers, these higher-income customers (primarily NEM customers) will avoid income-based fixed charges entirely. If residential income-based fixed charges adopted in R.22-07-005 do not eliminate cost shifting, the Commission should consider additional fixed charges on these customers that will fully eliminate the cost shift or separately consider a new track in R.22-07-005 to develop a no cost-shift tariff.

C. The Cost Shift Should Be Tracked and Publicly Reported

The PD states that its future evaluation of the NBT will focus on equity, affordability, and grid benefits.[27] Therefore, it is appropriate and essential for the Commission to track and publicly

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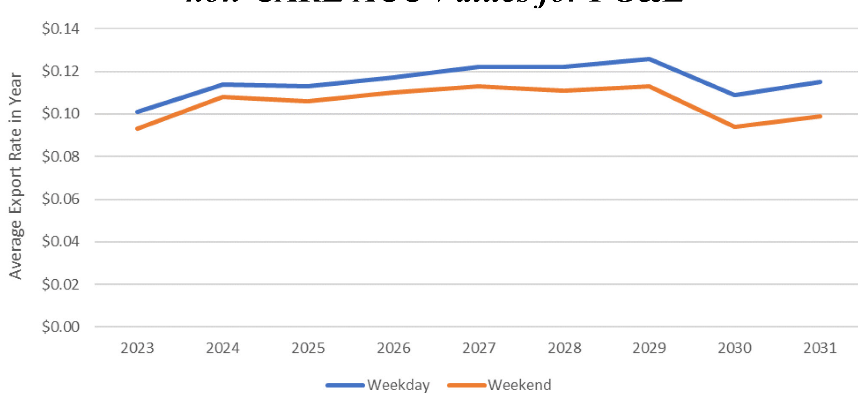
[24] PD, p. 211, FOF 212.
[25] PD, p. 184.
[26] Oral Argument transcript (Nov. 16, 2022), at 2299:12.
[27] PD, p. 189.

report the annual cost shift as part of its evaluation of the NBT, consistent with the methodology used in this proceeding to evaluate NEM 2.0 and successor tariff proposals. The Joint Utilities urge the Commission to report these numbers (the NEM 1.0/2.0 cost shift and, separately, the NBT cost shift) annually to the Legislature and to customers in the form of a bill insert or other notification. Decisionmakers and customers should understand they are subsidizing rooftop solar customers to the tune of billions of dollars annually. Today's bills show separate policy-driven rate components, like Public Purpose Programs (PPP) and Wildfire Fund Charge rates. However, because this PD maintains a large portion of the embedded cost shift, unless they are explicitly informed, non-participants will remain unaware of the costs they are paying to subsidize participating customers. Providing an annual report on the cost shift will increase transparency, better inform public understanding, and facilitate decision-making at a time when activities addressing State GHG and reliability goals place concurrent pressures on electric rates and customer bills. This may also enable a better understanding of whether the NBT is sufficiently addressing low-income customer needs.

D. Export Compensation Should Be Simplified

The PD adopts an export compensation structure that is the same for all rate classes, and provides a separate 24 hour price curve for weekdays and weekend in each month of the year, for a total of 576 possible export prices per year. Removing the weekday/weekend distinction and/or aggregating to the seasons of the underlying tariff would simplify the resulting tariff and improve customer acceptance. As reflected in Figure 1, the difference between weekday and weekend export rates is less than a cent and a half (lower in some years) based on current values.[28]

Figure I. Comparison of Average Export Rate – Weekdays vs. Weekend – Current non-CARE ACC Values for PG&E



28 The values in Figure I are taken from the PD's NBT model. The Joint Utilities corrected an error in the NBT model where SCE avoided cost values were duplicated for PG&E. The corrected PG&E values are inclusive of the ~$0.018/kWh ACC+ adder, though as stated in III.E, this adder is unnecessary.

Second, OP 2(a) states that "retail export compensation rates for residential [NBT] customers will be based on a nine-year schedule of values for each hour from the most recent ACC, adopted as of January 1 of the calendar year of the customer's interconnection date." This would mean a customer's export rate would need to be vintaged for nine years and different export values would have to be tracked and updated annually for a given customer based on the calendar year of their interconnection date. This would be true for each calendar year of the five-year glide path. This is unnecessarily complex, and implies a false precision of the forecasts embedded in the ACC. It also is confusing for customers and would be operationally arduous, resulting in a poor use of customer-funded resources. If the CPUC maintains a nine-year lock-in of export compensation values, it should, as a more reasonable approach, levelized the nine-year ACC schedule for a given cohort of customers for each calendar year of the five-year glide path. This would be both easier for customers to understand and more operationally feasible. To further improve simplicity for all stakeholders, a single set of export rates should be used for each two-year ACC update cycle.

Finally, we ask that the treatment for non-residential customers (which include industrial and agricultural customers) in OP 2.a. be clarified as reflected in Attachment A.

E. <u>ACC+ Adder Is Unnecessary For Non-Low Income Customers</u>

The PD uses a spreadsheet model to calculate the ACC+ adders needed to achieve an NBT target payback period of nine years. Even taking that target as a given, some of the core assumptions of the modeling relied on by the PD are incorrect, thus skewing the resulting paybacks unrealistically high. These assumptions are identified below and should be corrected.

First, the average solar customer (and associated system size) in the PD's modeling is unrealistically small, with modeled system sizes ranging from 3.4 to 3.8 kW_{AC} by utility. The actual average is over 5 kW.[29] Further, the modeling assumes that customers size their systems to offset exactly 100 percent of their annual usage. In practice, customers on average size to offset less than 100 percent. In the context of the NBT, sizing to 100 percent is less likely than under NEM 2.0 due to the lower value of export compensation. Adjusting the model to assume a 90 percent usage offset and an average pre-Distributed Generation usage of 12,000 kWh (resulting in a 5 to 5.4 kW_{AC} system size by utility, more closely matching the actual average) reduces the simple payback to 7.58, 8.05, and 4.74 years for PG&E, SCE, and SDG&E non-CARE NBT customers without any ACC+ adder, respectively.

Second, the PD also adopts $3.30/W as the cost of residential solar, picking a "compromise"

[29] Ex. PAO-01, p. 3-43.

value between the $3.8/W and NREL's $2.3/W, which the PD appears to acknowledge the solar parties previously recommended.[30] Rather than picking an arbitrary number, the final decision should instead use EnergySage's $2.8/W, which is a matter of record in this proceeding. This reflects actual pricing provided to customers in a more competitive segment of the rooftop solar market. Moreover, this data source was used by SEIA in this proceeding, albeit only for calculating paybacks in other states.

Third, the PD's underlying assumption that simple payback should be the customer economics target is questionable. The NREL research that the PD cites to support this metric underscores the importance of avoiding future rate increases.[31] That the CPUC felt the need to regulate the rate escalator that could be used to market residential solar as a consumer protection measure highlights that the actual marketing used by solar firms is more in line with the "time to payback" or "escalated payback" metrics that the CPUC's modeling also produces. Looking at this payback metric instead of simple payback, payback times are well below nine years for all non-CARE customers under the NBT even without making the adjustments described above.

Setting aside the modeling assumptions, the PD's dicta appropriately excludes new construction customers from receiving the ACC+ adder, as new construction customers are required to install solar and do not need the additional incentives.[32] The Joint Utilities recommend this ineligibility be expressly stated in an OP. Similarly, customers transitioning from NEM 1.0 or NEM 2.0 to the NBT at the end of their legacy period should not be eligible for the adder as they have already enjoyed 20 years of subsidy.

F. <u>NEMA And VNEM Tariff Changes Should Be Clarified</u>

The Joint Utilities largely agree with the findings and conclusions of the PD regarding NEMA and VNEM, but the dicta in the PD is inconsistent with the PD's modeling. As modeled, the PD adopts an entirely new structure that was never the subject of testimony or briefs, and hence never part of the evidentiary record.[33] This approach would have the utilities allocate exports in each metered interval to each benefiting meter in a VNEM and NEMA arrangement and calculate how many kWh would have been consumed behind the meter and how many kWh would have been exported had the allocated generation actually occurred behind the meter. In effect, metered exports

[30] PD, pp. 79-80.
[31] PD, p. 76.
[32] PD, pp. 144-145.
[33] It appears this concept was first raised by Ivy Energy in comments on the original decision, after the closure of the record, and even here was secondary to Ivy's primary proposal that VNEM should be remain unchanged.

are partially accorded retail-based compensation. This will be very complicated and expensive to implement and administer and is likely to produce counterintuitive incentives.[34] Rather than require this unvetted and extra-record approach, the PD should be revised to clarify that all metered exports will receive ACC-based credits and provide higher ACC+ credits to residential VNEM customers to achieve a similar nine-year payback period. This will provide transparent and equitable compensation to all benefiting accounts and actionable, predictable incentives to paired storage systems. Based on the modeling changes detailed in Attachment B, this requires a $0.0475, $0.0448, and $0.035 ACC+ adder for PG&E, SCE, and SDG&E, respectively. Since this is based on the ACC, the adder does not need to be differentiated for low-income customers. If the CPUC believes that virtual tariff compensation should be higher for more than nine years, it should modify the parameters of the ACC+ mechanism for these customers, not require a complicated netting scheme.

Moreover, the assumptions in the PD's related modeling spreadsheet appear to be based on a misconception of how NEMA and VNEM currently work. The decision requires that for VNEM and NEMA "netting intervals shall remain unchanged from the current net energy metering tariff."[35] However, no netting at the metering interval level currently occurs – NEMA and VNEM benefiting accounts are assessed NBCs based on their total usage from the grid and allocated energy credits based on a fixed percentage (VNEM) or based on the benefitting accounts' proportional total usage since the start of their true-up period (NEMA). In fact, the CPUC rejected a proposed approach like the one here during implementation of the current tariff.[36] The PD does not explicitly require a change to the way that NEMA and VNEM credits would be allocated but instead assumes that energy credits are already allocated based on consumption within each interval. If the Commission does adopt interval netting for VNEM and NEMA successors it should do so while making no changes to the credit allocation methods currently in place.[37]

The PD accepts Ivy Energy's argument that there is onsite usage of VNEM generation. Ivy cites an illustrative example and utility data that 94 percent of VNEM benefiting meters are located

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34 For example, would a VNEM solar+storage system be optimized to minimize "exports" for tenants or common area meters that are the responsibility of the landlord?

35 PD, p. 222, COL 10 and 12.

36 In the implementation process of NEM 2.0, parties representing the solar industry and agricultural customers argued for treatment similar to that possibly granted in this PD and which were rejected by the Commission.in Resolution E-4729, pp. 6-7. That resolution recommended those parties make other filings if they thought such treatment was justified, but they never did (even in the extant proceeding).

37 For example, a VNEM arrangement with 10 benefiters each receiving 10% of the total generation would receive 10% of the exports for each interval regardless of that benefiters' consumption during that same interval. Those exports would be net against the benefiters consumption for the interval and any excess exports would be credited at the export compensation rate.

on the same feeder as the generating account. That it is even possible for VNEM arrangements to split a distribution feeder should be taken as a flaw, but Ivy ignores that 31 percent of VNEM and 69 percent of NEMA (by far the larger tariff by MW of installed capacity) benefiting meters are located behind a different distribution transformer than the generating meter.[38] The utilities do not dispute that a portion of VNEM/NEMA metered exports may in fact be consumed by another meter without physical exports, but under the approach adopted by the PD it is certain that some physical exports onto the high voltage distribution system would be compensated at retail rates.

To the extent the final decision maintains this novel, unsupported netting treatment for any customers, it should be reserved for residential VNEM arrangements only, which can provide onsite solar access to underserved renters. It absolutely should not be provided to NEMA as: (i) NEMA generating accounts can have onsite load (unlike VNEM); and (ii) the legislation enabling NEMA requires that NEMA not increase costs for other customers, which would clearly not be true in the context of the uncapped successor tariff.[39] No party seriously contests that retail-based compensation for solar exports exceeds the value of that generation as estimated by the ACC; maintaining export credits for NEMA other than something based on the ACC would be legal error.

Lastly, the PD should be revised to rename the new versions of NEMA and VNEM to NBTA and NBTV to clarify that these tariffs are based on the general market NBT, not NEM.

G. Residential Virtual NBT Customers Should Be Required to Use the Same Rates as Others

If the above proposed clarifications to VNEM are not adopted, and in any case for NEMA, the Final Decision should require residential customers taking service on the NBT in a virtual arrangement to utilize the same underlying rate as other NBT residential customers.[40] While the Joint Utilities recognize that tenants have less ability to invest in technologies that would help them shift load, this logic does not apply to residential NEMA customers, and implementing the NBT for all rates that a virtual benefitting account may choose will result in millions of dollars of added cost. This is an unreasonable use of customer dollars. Furthermore, it is important to consider that renters have the ability to shift load through behavioral and some technological choices (*i.e.,* microheating with space heaters). PG&E currently has only about 3,900 residential non- low-income VNEM customers and 12,000 residential NEMA customers. It is unreasonable to ask all customers to spend significantly more to build additional billing IT infrastructure to benefit a limited set of customers.

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38 Ex. IOU-02, pp. 109-110.

39 While NEM 2.0 maintained NEMA, this was understood in the context of the NEM 2.0 decision largely declining to make findings regarding cost effectiveness.

40 PD, p. 175.

IV. TECHNICAL & IMPLEMENTATION CONSIDERATIONS

A. Cost Recovery for the Memorandum Account Should Be Clarified and the Tariff Filing Timeline Should Be Adjusted

OP 13 authorizes the Joint Utilities to jointly file an advice letter to establish memorandum accounts; however, the OP does not appear to reference the correct sections in the PD and additional modifications should be made. Specifically, because each of the Joint Utilities will manage their own memorandum account, a joint filing is unnecessary. The Joint Utilities also request the Final Decision authorize the recording of costs to the memorandum accounts as of the date of the Final Decision. This is important because the Joint Utilities will need to move quickly with billing implementation and marketing, education and outreach work to facilitate the transition to the NBT and will immediately incur costs. Finally, the Commission should clarify that the costs may be recovered through a future General Rate Case (GRC) application. The Joint Utilities support the order that requests for the Memorandum Account be filed 30 days after the adoption of the decision.

Regarding the timing of the tariff filings outlined in OP 13(b) and (c), the Joint Utilities request that the separate Tier 1 filings be consolidated into a single filing, due 45 days from the Final Decision. Assuming a Final Decision is adopted on December 15, 30 days will not be enough time to properly draft complete tariffs and coordinate across utilities over the holiday period. Furthermore, a single filing at 45 days will be more efficient and avoid unnecessary confusion for all, while still allowing sufficient time for staff to review and dispose of the advice letter.

B. Cost Recovery for the ACC+ Adder Should Be Clarified

OP 2.b. states that funding for the ACC+ adder will be provided by all ratepayers through the Public Purpose Program (PPP) charge, but the OP does not specify the cost recovery mechanism to do so. The Joint Utilities request that the Final Decision authorize a two-way balancing account to record and recover the ACC+ adder from all ratepayers through the PPP charge. PPP rates will be trued-up on an annual basis through the IOUs' respective annual electric true-up advice letter.

C. The Joint Utilities Should Not Be Required to Notify Customers About the Performance of Their Solar Generation Systems

OP 3 directs the Joint Utilities to "notify net billing tariff customers within 24 hours of when their solar systems appear to be offline for a period of seven days or more." While the Joint Utilities appreciate the intent of this directive, we do not have the information necessary to meet this directive in a way that would provide customers accurate information. For customers who have installed solar generators, the Joint Utilities generally have access to bidirectional meters that record import and exports, but do not have access to solar generation data. Exports are the net of onsite consumption and solar generation. If exports decrease, it does not necessarily mean that the customer's solar system is not producing. Whether through behavior changes, storage, or smart-appliances, customers may adjust their consumption to better coincide with solar generation. In addition, in winter months, it can be normal for a customer with solar not to export to the grid given that solar generation in winter is about 40 percent of generation in summer months. The Joint Utilities are concerned that, based on our incomplete data, notifying customers who do not export could result in confusion and unnecessary alarm.

Furthermore, the Joint Utilities were unable to find anything in the evidentiary record related to this directive, including the feasibility and cost to implement and administer. It should be stricken in the Final Decision. As an alternative, we suggest that the Commission update the California Solar Consumer Protection Information Guide to further emphasize the importance of ensuring that customers leverage solar performance monitoring systems which are readily available to most customers either through their solar providers or through a third party.

D. The Requirement for Joint Utilities to Provide 15-Minute Interval Data Should be Stricken

The PD directs the utilities "to include both channels of data in 15-minute intervals in their customer-authorized energy usage data portals."[41] The assumption is that this data is needed to forecast bill savings for prospective solar and solar + storage customers.

Providing 15-minute interval data for all residential customers would be a multi-year and multi-million-dollar effort without a corresponding benefit to prospective solar customers. There would be significant cost in scaling the current interval meter data management infrastructure for residential customers (which is based on 60-minute meter intervals) to manage four times as much data. The record does not demonstrate that providing this more granular data would meaningfully improve forecasted customer bill savings over the life of a solar system compared to using the 60-minute Green Button data currently available for residential customers. The hourly Green Button data is generally used by solar providers to provide bill savings estimates (although some providers use even less granular data such as monthly bill usage to provide bill savings estimates). Moreover, many other factors may have a larger impact on actual versus forecasted financial return such as the customer's future energy usage, future rates, as well as weather and technological factors that may affect solar production.

The PD states that the Joint Utilities testified that we have the ability to provide 15-minute interval data. To clarify, the utilities can provide 15-minute interval data at a limited scale for

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[41] PD, p. 129.

residential customers who: 1) have a SmartMeter; 2) are registered in the CAISO's Demand Response Registration System with third party Demand Response Providers per the utilities' Rule 24 and 32 Demand Response programs; 3) notify the utilities that they would like their meters reprogrammed for 15-minute rather than the 60-minute intervals that residential meters currently capture for billing purposes; and 4) use utilities special data sharing protocols. The utilities do not make 15-minute interval data available for all residential customers.

E. The Nine-Year Schedule For ECR and ACC+ Eligibility Should Be Clarified

When discussing the nine-year legacy period, the PD states that the "nine-year legacy period is meant to provide the enrolled customer with certainty about the terms of their investment"[42] and that the "legacy period is linked to the customer who originally causes the system to be installed, not to the system itself."[43] The Joint Utilities interpret this to mean that the original customer who installed the generation system is eligible to remain on the NBT tariff for nine years from the date of interconnection. The PD is currently unclear as to whether this original customer requirement also applies to the lock-in period for the schedule of values to be used to calculate the export compensation rate.[44] As the stated intent of the legacy period is to provide the customer with certainty, the Joint Utilities recommend that the Final Decision clarify that the ECR lock-in period is only applicable to the customer who installed the generation system. Likewise, considering the intent of the ACC+ adder,[45] the Final Decision should clarify that the adder is only available to the customer who installed the generation system (assuming it is otherwise applicable). The Joint Utilities recommend an additional OP to provide clarity regarding the interaction of the legacy period, and eligibility for the ECR price schedule, and ACC+.

F. The Timeline For PG&E's Billing Implementation Should Be Adjusted

OP 13(f) requires the Joint Utilities to implement the NBT in their billing systems no later than 12 months from the adoption of the Final Decision. The Joint Utilities recognize the importance of expeditiously operationalizing this tariff. SCE and SDG&E should be able to meet this timeline. PG&E requests authorization to implement the NBT in two phases over a total of eighteen months after the adoption of the final decision. Phase 1 will implement the NBT for residential customers adopting solar or solar paired storage within 12 months. The cost shift is most

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42 PD, p 156.

43 Ibid.

44 PD, p 138.

45 PD, p 142 ("inclusion of a glidepath is essential, and the ACC Plus is the best and most transparent approach.… This glide path will be available to eligible successor tariff customers for the first five years of the successor tariff and will ensure a reasonable level of monthly bill savings.")

sizable for this set of customers, and PG&E will prioritize transitioning them to NBT first, which will address nearly three-quarters of the cost shift that results when new customers enroll on NEM 2.0. Phase 2 will focus on non-residential customers and complex NBT schedules and sub-schedules such as virtual net billing, multiple technology net billing, and aggregated net billing for residential and non-residential customers. Because the 12-month timeframe provided in the PD is intended to stem the NEM 2.0 cost shift quickly, PG&E asks that the Commission find it reasonable for PG&E to implement the NBT in these two phases.

PG&E needs 18 months to complete NBT implementation because it is undergoing a billing system modernization project and is limited in the number of changes that can be completed at one time.[46] The 18-month timeline to implement NBT will be completed simultaneously with other critical projects focused on achieving California policy objectives, including reliability, affordability and decarbonization, with little or no impact to their required implementation timing, including the Commercial Electric Vehicle (CEV) opt-in Real-Time Pricing (RTP) rate and non-NEM export pilot rate, the GRC Phase 2 Commercial and Residential RTP Pilots, EV Submetering, the Electric Home Residential electrification rate (E-ELEC), and the Percentage of Income Payment Plan pilot.

G. PG&E Requests Flexibility on When Customers Take Service on E-ELEC

Finally, PG&E asks for an adjustment to the PD's requirement that customers temporarily billed on NEM 2.0 "take service on the appropriate time-of-use rates adopted in this decision."[47] PG&E will not have the E-ELEC rate available before the anticipated NEM sunset date if a Final Decision is adopted on December 15, 2022. PG&E asks that NBT customers temporarily billed on NEM 2.0 to take service on rates available to NEM 2.0 customers during this interim period. These customers will then be moved to E-ELEC when they transition to the NBT.

H. The Joint Utilities Should Pause Transitioning NEM 1.0 Customers As Soon As Practicable

The PD directs the Joint Utilities to pause transitions for NEM 1.0 customers between the NEM 2.0 sunset and NBT implementation to avoid serial transitions from NEM 1.0 to NEM 2.0 to NBT.[48] The Joint Utilities recommend that they be allowed to pause transitioning these customers as soon as practicable (including before the NEM 2.0 sunset) following issuance of the Final Decision. Implementing the pause is not complex and pausing sooner will allow more customers to

[46] PG&E briefed the Energy Division in late 2021 about its billing project, and the resulting constraints on the billing system work that could be completed over the following several years, highlighting its efforts to prioritize existing and new compliance requirements. PG&E also has communicated with involved parties and worked to develop workarounds when possible. Workarounds include manual billing solutions, phased implementations, and obtaining additional time to comply under Rule 16.6.

[47] PD, p. 187.

[48] PD, p. 188.

avoid two transitions in quick succession.

I. NEM 2.0 Applications Should Be Subject to a Completion Timeline; Discretion to Grant NEM 2.0 for Utility-Caused Delays

OP 13(e) states the milestone for an interconnection application to be eligible for NEM 2.0 is a "complete application." It is important to ensure all NEM 2.0 applications are valid and do not linger in the interconnection system. Thus, the Joint Utilities recommend adding a timeline for applications to submit final building permit sign off / electrical clearance by the authority having jurisdiction within one year of application submission for projects sized less than 30kW and two years for projects sized greater than 30kW. Further, the Joint Utilities should be granted discretion to give NEM 2.0 eligibility that fail to submit a complete application due to utility-caused delays.

J. Ordering Paragraph 2 Should Specify the Monthly Payment Requirement

The PD "requires residential customers and nonresidential customers to pay their bills monthly, meaning customers must pay all incurred charges every month."[49] The Joint Utilities support this requirement and recommend language be added to the OPs for clarity.

K. PG&E & SCE Currently Allow Customers to Change Their True-Up Date Under NEM

OP 5 of the PD requires the Joint Utilities to develop a process to allow customers to choose their true-up date under the NBT. SCE and PG&E already have such processes in place.[50] Thus, this OP should be revised to state that only SDG&E should develop a new process for this purpose.

V. CONCLUSION

The Joint Utilities urge the Commission to adopt a final decision containing the proposed modifications discussed above and as listed in Attachment A.

Respectfully submitted on behalf of the Joint IOUs,
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Dated: November 30, 2022

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49 PD, p. 132.

50 *See* SCE Schedule NEM-ST Net Energy Metering Successor Tariff Special Condition 1.j.iii.

ATTACHMENT A

Joint IOUs' Proposed Modifications to Findings, Conclusions, and Orders

Joint Utilities' Proposed Modifications to Findings, Conclusions, and Orders

Proposed text deletions are in bold and strikethrough (**~~abcd~~**)

Proposed text additions are in bold and underlined (**abcd**)

Findings of Fact	*Proposed Modification*
1. The evaluation of NEM 2.0 tells the Commission whether the tariff is or is not performing as required.	
2. The evaluation of NEM 2.0 establishes a foundation for creating a successor tariff.	
3. The Lookback Study does not tell a complete story but informs the Commission on how the successor tariff should be revised.	
4. The NEM 2.0 tariff negatively impacts non-participant ratepayers.	
5. The NEM 2.0 tariff is not cost-effective for the commercial, industrial, and agricultural customer segments.	
6. The NEM 2.0 tariff is not cost-effective for the residential customer segment.	
7. The NEM 2.0 tariff disproportionately harms low-income customers.	
8. A disagreement on an assumption in the Lookback Study does not equate to a flaw in that assumption.	
9. The cost-effectiveness analysis in the Lookback Study was conducted in accordance with prior Commission decisions.	
10. The Lookback Study is a sound analysis of the NEM 2.0 tariff.	
11. The Affordability Report indicates high electricity rates are driven by a combination of transmission and distribution costs, wildfire mitigation, and the shifted costs from solar customers to customers without solar.	

12. The cost shift discussion in this proceeding does not ignore the other drivers of high electricity rates but, rather, focuses on the one driver that is relevant to this proceeding: the significant cost shift from solar customers to customers without solar.	
13. NEM 2.0 tariff customers bypass infrastructure and other service costs embedded in volumetric rates by decreasing grid imports.	
14. The bypassed infrastructure and other service costs embedded in volumetric rates by NEM 2.0 participants over the course of the 20-year legacy period are shifted to non-participant ratepayers.	
15. The Lookback Study indicates NEM 2.0 negatively impacts non-participant ratepayers.	
16. The precise financial impact of NEM 2.0 on nonparticipant ratepayers depends on the Avoided Cost Calculator values used.	
17. PCF's analysis and estimate of the financial impact of NEM 2.0 are incorrect.	
18. The financial impact of NEM 2.0 is caused by more than the simple bill savings from net energy metering customer energy consumption.	
19. Without changes to the current tariff structure, the financial burden on the shrinking pool of nonparticipants is unsustainable and would fall disproportionately on lower-income customers.	
20. The Lookback Study finds that the commercial, industrial, and agricultural customer segments of the NEM 2.0 tariff generally pass the TRC test and pay rates that fully cover their costs of services.	
21. No party other than PCF disputes the cost-effectiveness results of the commercial, industrial, and agricultural segments of the NEM 2.0 tariff.	

22. The Lookback Study followed the directives of prior Commission decisions regarding the methods for cost-effectiveness analysis.	
23. While the Lookback Study found commercial, agricultural, and industrial sectors of the NEM 2.0 tariff had TRC test and PCT results of 1.0 or better, the results of the RIM test showed a benefit-cost ratio of less than 1.0.	
24. The Lookback Study indicates the nonresidential sectors of the NEM 2.0 tariff are not cost-effective.	
25. The Lookback Study finds the NEM 2.0 tariff is not cost-effective for the residential customer segment.	
26. Lower-income customers are burdened with the additional expense of a portion of the 82 to 91 percent of the cost of service bypassed by NEM 2.0 residential customers whose bill payments only cover nine to 18 percent of their cost of service.	
27. The Lookback Study indicates that the NEM 2.0 tariff disproportionately harms low-income customers not participating in the tariff.	
28. The Lookback Study indicates that the NEM 2.0 tariff disproportionately benefits non-CARE residential NEM 2.0 tariff customers while all other customers, including those with lower incomes, bear the addition of 82 to 91 percent of the cost of service bypassed by these tariff customers.	
29. Parties have varying interpretations of the phrase “grow sustainably” and what that means for the successor tariff.	
30. In D.16-09-036, the Commission stated it was not placing a greater emphasis on achieving sustainable growth over other statutory obligations, and nothing in the record of this proceeding leads the Commission to stray from this	

position.	
31. Any proposed change to the net energy metering tariff should consider the impact on the growth of the net energy metering market and, therefore, the solar industry.	
32. Allowing the net energy metering tariff to result in growing costs shifted to non-participants is not sustainable to the overall health of net energy metering.	
33. The net energy metering tariff has and should continue to assist California in meeting its energy and climate goals.	
34. The Commission considered and adopted estimates of transmission and distribution costs, greenhouse gas reductions, and system resiliency and reliability in D.20-04-010.	
35. The Standard Practice Manual states that the cost-effectiveness tests should not be used individually, but instead consider the tradeoffs between the tests.	
36. D.19-05-019 directs the use of the TRC and recognizes the importance of the PAC and RIM tests.	
37. Each cost-effectiveness test has value and together the tests tell a complete story.	
38. Consideration of all the cost-effectiveness tests allows the Commission to consider the values of and tradeoffs between the tests.	
39. Application of the Societal Cost Test is premature because the evaluationto determine the final details of the test has not been completed.	
40. D.20-04-010 concluded that consideration of the benefits of grid services provided by specific distributed energy resources should be addressed in resource-specific proceedings.	

41. D.20-04-010 considered SEIA/Vote Solar's proposals for avoided reliability and resiliency costs and found the benefits described could only be attributable to stand-alone solar and solar paired with storage.	
42. D.20-04-010 found the SEIA/Vote Solar proposal for avoided reliability and resiliency costs did not show any deferred or avoided costs to utility ratepayers but indicated ratepayers using these technologies receive additional participant benefits.	
43. Neither SEIA/Vote Solar nor PCF provide convincing evidence that the examples of resiliency benefits offered are more than individual benefits.	
44. Examples given by SEIA/Vote Solar and PCF are either private or highly speculative and limited to unique circumstances.	
45. The proposed societal benefits of an updated social cost of carbon metric, a reduced methane leakage multiplier, and future transmission costs are not solely applicable to net energy metering.	
46. In-state methane leakage is accounted for in the Avoided Cost Calculator.	
47. Allowing for an additional value for societal benefits associated with in-state methane leakage would result in the double counting of this benefit.	
48. In D.22-05-002, the Commission declined to adopt a proposal to include out-of-state methane leakage values in the Avoided Cost Calculator.	
49. Neither CALSSA nor SEIA/Vote Solar offer any evidence that increased net energy metering installations will directly result in decreased utility-scale projects.	
50. Parties agree to differing degrees that the Commission should consider the length of time for a customer's payback period when determining the	

reasonableness of the successor tariff.	
51. Analysis of the successor tariff requires balancing multiple legislative requirements and guiding principles, and the needs of participants and nonparticipants.	
52. Payback periods are not the predominant factor for customers when considering solar adoption.	
53. The 2013 and 2017 NREL studies show that consumers look at monthly bill savings when making an economic decision on adopting solar.	
54. It is reasonable to consider the length of time for a customer's payback period when determining the reasonableness of the successor tariff.	
55. A simple payback metric is the most transparent and consumer-friendly metric to determine the number of years to payback.	
56. A target of a nine-year simple payback period for a stand-alone solar system presents a balanced approach to promoting the adoption of solar systems paired with storage.	56. A target of a nine-year simple payback period for a stand-alone solar system **does not** present a balanced approach to promoting the adoption of solar systems paired with storage.
57. The increased number of years to payback will alleviate cost shift in the successor tariff.	
58. The number of years to payback should reflect all costs of stand-alone solar and solar paired with storage adoption.	
59. The $2.34 per watt value for the cost of solar does not include costs for financing, electrical panel upgrades, or installation delays.	
60. SEIA/Vote Solar and CALSSA concede that $3.80 per watt is high for the cost of solar.	
61. The value of $3.30 per watt for the cost of solar reasonably accounts for electrical panel upgrades, delays, and the current inflationary costs.	61. The **EnergySage** value of $~~3.30~~**2.80** per watt for the cost of solar reasonably accounts for electrical panel upgrades, delays, and the current inflationary costs.
62. The White Paper proposed that preservation of a viable market is	

likely to require a glide path including both a gradual rate reform and an external transitional support mechanism designed specifically to enable a reasonable payback period for customers investing in onsite generation.	
63. Inclusion of a glide path is essential to balance the multiple requirements the tariff should meet.	
64. The magnitude and severity of the NEM 2.0 cost shift requires immediate action by the Commission.	
65. The glide paths proposed by CALSSA and SEIA/Vote Solar are inadequate, with respect to the length of time involved, for addressing the magnitude and severity of the cost shift.	
66. A five-year glide path provides a balanced approach that allows for sustainable market growth that does not occur at the undue and burdensome financial expense of nonparticipant ratepayers.	
67. A five-year glide path minimizes any cost shift to ensure equity among all customers and allow the industry to transition to one that promotes the adoption of solar systems paired with storage.	
68. The equity issue in this proceeding cannot be addressed solely by reducing the cost shift.	
69. State policy requires that disadvantaged communities not continue to be left behind with respect to clean energy options, including electrification and storage.	
70. Continuation of the existing cost shift feeds into higher electricity rates, which discourages the adoption of electrification measures.	
71. The objectives of the Lookback Study were to examine the impacts of the NEM 2.0 tariffs and to compare how	

different metrics have changed following the transition from the NEM 1.0 tariff to the NEM 2.0 tariff.	
72. Electricity consumption patterns are not discussed in the key takeaways of the Lookback Study.	
73. Energy consumption patterns included in the Lookback Study contain insufficient data to make the assertion that the current structure of net energy metering promotes electrification.	
74. The Lookback Study contains incomplete data regarding change in energy consumption for SCE's customers.	
75. Without complete data and more in-depth analysis on electricity consumption patterns, assertions regarding the promotion of electrification cannot be made or relied upon in this decision.	
76. The Lookback Study does not indicate that the current structure of net energy metering promotes electrification goals.	
77. The Commission has consistently conveyed the message that net energy metering systems should be sized to a customer's onsite load.	
78. Policy messages regarding sizing net energy metering systems to load were conveyed prior to the contemplation of the electrification policy.	
79. D.06-01-024, D.06-07-028, D.11-06-016 and D.14-11-001 do not address the policy of electrification.	
80. SEIA/Vote Solar's proposal to allow customers to oversize their systems by 50 percent, with the modification to compensate the net surplus generation at the current net surplus compensation rate, will promote electrification.	

81. The Commission is not revising the net surplus compensation rate currently set at the Default Load Aggregation Point price.	
82. The addition of storage provides greater benefits to both the customer and the grid as compared to the benefits of a stand-alone solar system.	
83. The Lookback Study found that the TRC benefit-cost ratio is consistently higher for solar photovoltaic systems when compared to solar paired with storage systems.	
84. The current cost of storage not only creates cost-effectiveness concerns, but also presents a barrier to widespread adoption.	
85. It is the policy of the Commission to encourage paired storage with the benefits and costs in mind.	
86. Continuing to base retail export compensation rates on retail import rates conflicts with the guiding principles.	
87. Retail rates do not reflect the actual costs of the exports or the benefits the exports provide to all customers and the electrical system.	
88. The Commission needs to know export actual costs and benefits in order to ensure they are approximately equal pursuant to Section 2827.1.	
89. Basing retail export compensation rates on retail import rates has resulted in compensation levels 3.8 to 5.4 times higher than the benefits they provide to the electrical systems in the form of avoided costs.	
90. Using avoided cost values instead of the retail rate brings the cost of the successor tariff closer to its value, which will ensure equity among customers and maximize the value of the resource to all customers and to the electrical system.	

91. Basing retail export compensation rates on Avoided Cost Calculator values sends more accurate price signals and promotes paired storage.	
92. Ensuring the growth of customer-sited renewable generation is not the Commission's only concern.	
93. Using the Avoided Cost Calculator approach will ensure the costs and benefits are approximately equal, as instructed by the Legislature.	
94. Using the Avoided Cost Calculator approach leads to positive outcomes for customers and nonparticipating ratepayers.	
95. With the exception of the 2020 version of the Avoided Cost Calculator, the calculator has consistently reflected the value of exported energy from year to year.	
96. Using Avoided Cost Calculator values to set retail export compensation rates will ensure the retail export compensation rate is based on the benefits provided to the electric grid and will reduce the cost shift.	
97. The Commission can use other elements and tools besides the stepped-down retail rate to transition to the successor tariff in a measured fashion.	
98. There are multiple elements to the retail export compensation rate, which can lead to confusion for customers.	
99. Requiring the same retail export compensation rate for all successor tariff customers will maintain equal treatment between nonresidential and residential customers, ensuring equity among customers.	
100. Adopting similar retail export compensation rates for new nonresidential successor tariff customers is reasonable.	
101. The Lookback Study highlighted that most nonresidential NEM 2.0	

customers have high fixed charges, minimum bills, and demand charges, which tend to lower the potential savings with solar systems.	
102. If the Commission were to find the NEM 2.0 structure compliant with guiding principles for the nonresidential customer sector, a change in demand charges or high fixed charges in another proceeding could lead to furthering the cost shift in net energy metering that could be challenging to unwind.	
103. Requiring successor tariff customers to take service on retail import rates with high differentials between winter off-peak and summer on-peak rates will improve the price signal to these customers.	
104. Requiring successor tariff customers to take service on highly differentiated time-of-use rates will incentivize customers to divert energy usage to lower-priced hours when the solar system is producing energy or to deploy storage.	
105. Highly differentiated time-of-use rates are closer to the energy prices required to run the grid.	
106. Requiring successor tariff customers to take service on highly differentiated time-of-use rates maximizes the value of the generation to all customers and to the electrical system and ensures equity among all customers.	
107. Highly differentiated time-of-use rates encourage electrification and help California reach its greenhouse gas emissions reduction goals.	
108. Requiring successor tariff customers to take service on highly differentiated time-of-use rates will meet several guiding principles in this proceeding.	
109. No evidence has been provided indicating that creating a highly differentiated time-of-use rate that is	

specific to net energy metering customers could discourage the adoption of multiple distributed energy resources.	
110. The current design of retail rates no longer provides the ability to accurately calculate a customer's energy and grid usage, with respect to net energy metering customers.	
111. Net energy metering customers intermittently reduce usage depending upon the performance of the solar system.	
112. The grid must always be prepared for the intermittent decrease and increase of a customer's usage.	
113. Net energy metering customers cause costs even when not directly importing energy from the grid.	
114. Retail rates were created before the emergence of the two-way street of imports and exports.	
115. The Commission initiated Rulemaking 22-07-005 to establish policies and modify electric rates to, among other objectives, enhance reliability and improve affordability and equity of bills.	
116. In R.22-07-005, the Commission will consider the reformation of fixed charges.	
117. R.22-07-005 is the appropriate regulatory venue to consider the issue of accurately calculating a customer's energy and grid usage and ensuring the grid is prepared for intermittent decrease and increase of usage.	
118. D.16-01-044 determined there are four non-bypassable charges that NEM 2.0 customers could not bypass by applying bill credits from exports; these charges are the public purpose program charge, nuclear decommissioning charge, competition transition charge, and Wildfire Fund Non-Bypassable Charge.	118. D.16-01-044 determined there are four non-bypassable charges that NEM 2.0 customers could not bypass by applying bill credits from exports; these charges are the public purpose program charge, nuclear decommissioning charge, competition transition charge, and **the <u>DWR Bond Charge, which in 2021 was replaced by the new, statutory</u>** Wildfire Fund Non-

119. Parties provided no evidence regarding why the list of non-bypassable charges adopted in D.16-01-044 should be expanded.	Bypassable Charge. 119. Parties provided **compelling** ~~no~~ evidence **that** ~~regarding~~ why the list of non-bypassable charges adopted in D.16-01-044 should be expanded **to include all non-bypassable charges newly enacted by the legislature since 2016 absent an express exemption for NEM**.
120. The ACC Plus is directly linked to the adopted retail export compensation value.	
121. The Market Transition Credit has no direct linkage to either the current export compensation structure of NEM 2.0 or the future structure of Avoided Cost Calculator-based values.	
122. While the retail rate step-down approach is linked to the current compensation structure, the adopted glide path will be provided to successor tariff customers who have never received retail export compensation rates based on the retail import rate.	
123. Basing the glide path on the Avoided Cost Calculator values ensures that values are current, as these values are updated every two years and changes to retail rates and time-of-use periods can be slow.	
124. The ACC Plus approach enables successor tariff customers to become familiar with the Avoided Cost Calculator values immediately compared to the retail rate step-down approach.	
125. The ACC Plus approach sends the right price signals to support the grid.	
126. It is reasonable during the transition period that stand-alone solar systems benefit more from the ACC Plus approach than solar paired with storage systems during the transition period.	

127. The ACC Plus approach will allow the industry to grow sustainably during the transition to a market that predominantly sells and leases solar paired with storage systems.	
(NEW)	**<u>It is not reasonable to allow the ACC Plus to fund required solar systems.</u>**
(NEW)	**<u>It is not reasonable to provide ACC Plus on positive net generation.</u>**
128. In D.15-07-001, the Commission adopted a minimum bill standard for residential customers on the non-generation portion of their monthly electric bill.	
129. In D.15-07-001, the Commission established a minimum bill of $5 for CARE customers and $10 for non-CARE customers.	
130. R.22-07-005 will consider the reformation of fixed charges, which could include the continuance or elimination of a minimum bill requirement.	
131. Hourly netting in the successor tariff could lead to additional strain on the grid.	
132. Eliminating the netting interval exposes more of the customers' imports and exports to net billing.	
133. No netting is more consistent with cost-based compensation and will maximize the value of customer-sited renewable generation to all customers and to the electrical system.	
134. An adjustment factor is useful as a proxy for no netting in developing estimates of monthly bill savings for prospective solar customers.	
135. Annual true-up periods allow generation to be credited for exactly what it is valued based upon the retail export compensation rate that hour.	
136. Annual true-up periods do not undermine greenhouse gas emissions objectives.	

137. Using hourly Avoided Cost Calculator values for retail export compensation rates complicates the bill structure.	
138. Averaging the Avoided Cost Calculator values across days in a month acknowledges the general trends in differences between hours and months and results in accurate values.	
139. Averaging the Avoided Cost Calculator values yields more accurate signals for customer generators to reduce imports from the grid and for battery storage to dispatch during hours most valuable to the grid.	
140. Averaging the Avoided Cost Calculator values across days in a month does not add the false precision of potentially inaccurate forecasts of a specific hour’s weather and other conditions.	
141. Using averaged monthly Avoided Cost Calculator values for retail export compensation rates ensures the tariff is based on the generator’s true costs and benefits to the grid and leads to equity among all ratepayers while maximizing the value of the generation to all ratepayers and to the electrical system.	
142. Dividing the export credit between the customer’s load serving entity and distribution utility (where the load serving entity is responsible for energy, cap and trade, and generation capacity while the distribution utility is responsible for transmission, distribution, greenhouse gas adder, and methane leakage) is consistent with current tariff approaches and considers competitive neutrality amongst load serving entities.	
143. Like all forecasts, the Avoided Cost Calculator forecast values are increasingly uncertain further away from the present.	

144. Basing the Avoided Cost Calculator values on a schedule of values will enable solar providers to predict customer savings.	144. Basing the Avoided Cost Calculator values on a **<u>levelized value set for a period of time</u>** ~~**schedule of values**~~ will enable solar providers to predict customer savings.
145. The certainty of a locked-in rate schedule helps to ensure that customer-sited renewable distributed generation continues to grow sustainably during the transition period.	145. The certainty of a locked-in rate **<u>value</u>** ~~**schedule**~~ helps to ensure that customer-sited renewable distributed generation continues to grow sustainably during the transition period.
146. Using a single year of Avoided Cost Calculator values, instead of values averaged across several years of the Avoided Cost Calculator, brings the cost of the tariff closer to its value.	
147. Using a single year of Avoided Cost Calculator values aligns with requirements to ensure the tariff is based on the costs and benefits of the customer generator and ensures the benefits are approximately equal to the total costs.	
148. Using retail export compensation rates specific to climate zones does not result in significantly more accurate Avoided Cost Calculator values.	
149. An objective of the glide path is to ensure reasonable payback periods for customers, especially low-income customers.	
150. Limiting the glide path to a small subset of customers would not ensure customer-sited renewable distribution generation continues to grow sustainably.	
151. The Commission does not intend the sustainable growth of the market to be focused solely on low-income customers.	
152. The glide path is meant to ensure successor tariff customers, including CARE- and FERA-enrolled customers, have a nine-year simple payback period for stand-alone solar	

systems.	
153. A fixed ACC Plus adder meets many objectives of this proceeding as compared to the multiplier.	
154. A multiplier ACC Plus adder might have perverse outcomes on battery discharge behavior and compensation.	
155. A fixed adder in the ACC Plus will provide more certainty to a customer by providing a predictable value.	
156. In combination with other elements of the successor tariff, ratepayer funding of the stepped-down ACC Plus approach appropriately balances tariff requirements.	
157. The proposed import retail rates will improve the pricing signal to successor tariff customers, increase the value of the generation to all customers and the electrical system, and encourage electrification.	
158. The transition to the successor tariff will require customers to make substantial investments in storage, as well as solar, with longer payback periods in comparison with the NEM 2.0 tariff.	
159. Net energy metering customers are more likely than other customers to choose critical peak pricing rates, which will help the grid during critical peak days.	
160. The availability of critical peak pricing and peak day pricing rates will enhance the value of stand-alone solar and solar paired with storage systems.	
161. The Joint Utilities' proposal to require bill credits be applied to charges in the same time-of-use period is overly prescriptive.	
162. D.16-01-044 required verification that solar system components are on the verified equipment list maintained by the CEC, which was required by the California Solar Initiative, and was	

duplicative of interconnection rules.	
163. The Net Billing tariff adopted here is not part of the California Solar Initiative.	
164. Equipment failures or other issues may cause a customer's solar system to go offline without the customer's knowledge, which may cause unanticipated increases to the customer's electric bill.	
165. Non-operating solar systems may result in underutilization of California's installed renewable energy resources and impact the State's ability to meet its environmental and climate goals.	165. ~~**Non-operating solar systems may result in underutilization of California's installed renewable energy resources and impact the State's ability to meet its environmental and climate goals.**~~
166. The successor tariff makes great strides in tackling the cost shift, thus addressing one element of the equity issue.	
167. The ACC Plus glide path assists the Commission in addressing the equity issues while also addressing the statutory requirement that customer-sited renewable distributed generation continues to grow sustainably.	
168. The successor tariff balances the requirements of the statute and the guiding principles previously adopted in this proceeding.	
169. Low-income households have financial challenges and barriers to adoption of behind-the-meter resources.	
170. The successor tariff is required to meet many objectives in addition to expanding access to low-income households.	
171. The Lookback Study found that low-income non-participating customers are most impacted by the cost shift that exists in the current net energy metering tariff.	
172. The record does not measure the impact that would occur if the Commission were to expand the	

definition of low-income beyond CARE- and FERA-enrolled customers.	
173. Installation of distributed generation is less frequent in low-income households and disadvantaged communities.	
174. The inability to achieve higher bill savings and reasonable payback periods are barriers to increased participation by low-income customers.	
175. Adopting the same net billing tariff structure regardless of household incomes meets the equity requirement in Guiding Principle (b).	
176. Providing discounts on certain elements of the tariff structure for eligible households (i.e., a higher ACC Plus adder) will assist the Commission in meeting the objectives of improved equity and increased participation in low-income households and disadvantaged communities.	
177. Low-income households have challenges with certain time-of-use rates and electrification costs due to the difficulty with load-shifting and affordability of smart appliances.	
178. Analysis of the successor tariff indicates greater bill savings with adoption of electrification rates by customers with solar systems paired with storage.	
179. The combination of the ACC Plus and an equity fund could assist the Commission in meeting the requirement to ensure specific alternatives designed for growth among residential customers in disadvantaged communities.	
180. An equity fund has been created by the legislature with the objective of improving access to distributed energy resources technology for low-income households and disadvantaged	

communities.	
181. A ruling has been issued in R.20-05-012 asking for comment on implementation of funds pursuant to AB 205, as well as eligibility and deployment requirements.	
182. A guiding principle in this proceeding is to ensure equity in the successor tariff.	
183. The Order Instituting Rulemaking for this proceeding stated that this proceeding would coordinate with other relevant proceedings.	
184. Information gathered in the affordability proceeding (R.18-07-006) and not in the record of this proceeding could be helpful in providing a more complete record with respect to the low-income VNEM subtariff.	
185. Ongoing triennial evaluations of the SOMAH program are being conducted, pursuant to D.17-12-022.	
186. A report of the SOMAH evaluation has been made public and the information in the evaluation could be useful in determining future changes to the tariff.	
187. The SOMAH evaluation is not in the record of this proceeding.	
188. It is prudent to delay any changes to low-income subtariffs of VNEM until review in this proceeding of findings from the affordability proceeding and the SOMAH evaluation.	
189. An objective in this proceeding is to ensure the successor tariff aligns with the costs and benefits of customer generation.	
190. Basing retail export compensation rates on retail import rates does not meet the objective of aligning costs and benefits of customer generation.	
191. Aligning the VNEM subtariff with the successor tariff balances the multiple and competing objectives in this	

proceeding.	
192. Tenants lack the ability to install storage and lack access to the net generation system.	
193. Tenants do not design, own, or manage the on-site generation system.	
194. Tenants have less ability and fewer options than property owners to install load-shifting smart devices and appliances.	
195. VNEM generation meters measuring output are separate from individual tenant or common-area meters measuring customer usage, which makes it impossible to require no netting under a net billing tariff.	195. VNEM generation meters measuring output are separate from individual tenant or common-area meters measuring customer usage~~**, which makes it impossible to require no netting under a net billing tariff**~~.
196. No netting is impossible for NEMA subtariff customers under a net billing tariff because no onsite generation is used to prevent imports by powering the benefiting accounts.	196. ~~**No netting is impossible for**~~ NEMA subtariff customers ~~**under a net billing tariff because no**~~ **can use** onsite generation ~~**is used**~~ to prevent imports ~~**by powering the benefiting accounts**~~.
197. Analysis shows that VNEM subtariff customers will have simple payback periods ranging between 4.03 and 7.20 years.	197. Analysis shows that VNEM subtariff customers will **require higher ACC+ adders than standard NBT customers to** have simple payback periods **of 9 years**. ~~**ranging between 4.03 and 7.20 years.**~~
198. Ivy Energy demonstrated there is onsite consumption of energy that is generated at multifamily buildings interconnected under VNEM; Joint Utilities do not dispute this claim in briefs.	198. Ivy Energy demonstrated there ~~**is**~~ **can be** onsite consumption of energy that is generated at multifamily buildings interconnected under VNEM; Joint Utilities do not dispute this claim in briefs.
199. It is reasonable to affirm that VNEM provides benefits to the grid similar to that of the NEM 2.0 tariff.	
200. VNEM is for multi-tenant buildings and is designed to facilitate a virtual metering billing arrangement.	
201. NEMA is available to a single customer that has a generating facility or facilities on adjacent or contiguous properties and allows for aggregation as if on one site.	
202. VNEM and NEMA serve separate purposes and generally have separate	

customer bases: VNEM for multi-tenant customers and NEMA for agricultural customers.	
203. The current VNEM subtariff allows multiple arrays but requires each array to serve a subset of customers on the property.	
204. Joint Utilities point to no engineering or policy reason why multiple solar arrays on one property should not be treated as one generator on the VNEM subtariff, with credits allocated across the property.	
205. Many apartment complexes contain more than one building and often require the use of separate roof surfaces and points of interconnection for VNEM.	
206. Treating multiple solar arrays on one property as one generator is reasonable, efficient, and aligns with existing MASH and SOMAH VNEM subtariffs.	
207. There are aspects of community solar that are being discussed or considered in other proceedings.	
208. In consolidated Applications A.22-05-022, A.22-05-023, and A.22-05-024 the Commission is reviewing utility applications for the Green Tariff Shared Renewables program, Disadvantaged Communities Green Tariff program, and Community Solar Green Tariff program.	
209. It is premature to adopt a Community Solar tariff or subtariff in this decision.	
210. In D.16-01-044, determinations regarding the NEM 2.0 tariff were made at a transitional moment without the advantage of a quantitively informed basis.	
211. The Commission now has the data to make an informed decision on a successor tariff.	
212. The Lookback Study found that NEM 2.0 is not cost-effective, has negatively	

impacted non-participant ratepayers, and has disproportionately harmed low-income customers.	
213. The estimated cost shift from the NEM 2.0 tariff ranges between $1 billion and $3.4 billion annually.	213. The estimated cost shift from the NEM 2.0 tariff ranges between $1 billion and $3.4 billion annually <u>**in 2021**</u>**.**
214. The changes made to the net energy metering tariff in Section 8.5 above do nothing to tackle the cost shift created by NEM 1.0 and NEM 2.0 customers; the changes only attempt to prevent or limit additional cost shift from new customers enrolling in the successor tariff.	
215. NEM 1.0 and NEM 2.0 are within the scope of Issue 6.	
216. In D.16-01-044, the Commission established a legacy period of 20 years from a customers' interconnection date as a reasonable period over which the customer should be eligible to continue taking service under the NEM 2.0 tariff.	
217. The choice regarding changes to NEM 1.0 and NEM 2.0 result in an inequity to one of two groups: nonparticipant ratepayers or legacy customer ratepayers.	
218. Public Utilities Code Section 2827.1 and the guiding principles do not rank the requirements for the successor tariff or tell the Commission whose needs should come first: the needs of a particular group of customers, the environment, or the grid.	
219. Determining whether to revise the NEM 1.0 and NEM 2.0 tariffs requires balancing various and competing requirements, and impacts participants, nonparticipants, the grid, and the environment.	
(NEW)	<u>**Allowing NEM 1.0 and 2.0 tariff customers to transition to the NBT would allow continuation of cost shifting to non-participant customers.**</u>

(NEW)	**<u>NEM 1.0 and 2.0 tariff customers should transition to a no-cost-shift-tariff after their 20-year legacy period ends.</u>**
220. In R.22-07-005, the Commission will consider the establishment of a fixed charge for all residential customers who use the grid.	222. In R.22-07-005, the Commission will consider the establishment of a fixed charge for all residential customers who use the grid, **<u>including NEM 1.0, 2.0, and NBT customers.</u>**
221. The fixed charge proposed in R.22-07-005 is intended to recover certain authorized utility costs that are currently collected through volumetric components of electricity bills.	
222. The record of this proceeding indicates that changes to each utility's billing systems and supporting platforms to bill customers on the successor tariff will take 12 to 24 months to upgrade following the adoption of a final decision.	
223. System completion following an interconnection application can be delayed for a host of reasons not in the customer's control.	
224. It is reasonable to define the interconnection application date as the submission date of an application that is free of major deficiencies and includes a complete application, a signed contract, a single-line diagram, a complete CSLB Solar Energy System Disclosure Document, a signed California Solar Consumer Protection Guide, and an oversizing attestation (if applicable).	
225. A Sunset Period will protect customers who are in the process of contracting for NEM 2.0 tariff service when this decision is adopted.	
226. Reducing benefits to customers taking interim service on the NEM 2.0 tariff following the Sunset Period would add an unnecessary layer of complexity.	
227. Billing system upgrades for each of the utilities are currently in progress.	

228. The utilities' request for additional time to implement their billing system upgrades is unreasonable.	
229. Between the NEM 2.0 tariff sunset date and Step 5, pausing any transitions of NEM 1.0 tariff customers to the NEM 2.0 tariff that would normally occur will eliminates the need for customers to understand a tariff on which they would only take service for a short period of time.	
230. A one-year implementation period for the successor tariff will allow behind-the-meter industry providers to sufficiently train their sales force and customer service representatives, and revise marketing material and contracts; and prevent additional contribution to the cost shift, ensure the compensation for these services is cost-effective, and initiate the storage and electrification benefits of the successor tariff.	
231. The Commission intends to collect data from the successor tariff for three years, and then analyze the data and provide a draft evaluation within five years of implementation of the successor tariff.	

Conclusions of Law	*Proposed Modification*
1. The Commission should use the Lookback Study as a foundation to create a successor tariff that continues the elements that resulted in positive outcomes but corrects or replaces elements that resulted in negative outcomes.	
2. The Commission should ensure the growth of the net energy metering market does not come at the undue and burdensome financial expense of nonparticipant ratepayers.	
3. The Commission should not grant the request to replace the Avoided Cost Calculator with the Lookback Study cost of service analysis.	
4. The Commission should align its analysis in this proceeding with prior guidance from the Standard Practice Manual and consider the value of the TRC, PCT, and RIM cost-effectiveness tests, as well as the tradeoffs between the tests.	
5. The Commission should not use the Societal Cost Test in its analysis of the successor tariff.	
6. The Commission should not ascribe a resiliency adder for net energy metering customers.	
7. The Commission should not adopt proposed societal benefits of an updated social cost of carbon metric, land conservation, a reduced methane leakage multiplier, or avoided transmission costs.	
8. The Commission should not rely on one single method of analysis to be the determinant of the final successor tariff.	
9. The Commission should consider monthly bill savings and a simple payback period target of nine years for a stand-alone solar system as part of the successor tariff.	9. The Commission should consider monthly bill savings and ~~**a simple**~~ **time to** payback period ~~**target of nine years**~~ for a stand-alone solar system as part of the successor tariff.

10. The Commission should adopt the value of $3.30 per watt as the cost of solar.	10. The Commission should adopt the value of ~~**$3.30**~~ **<u>$2.80</u>** per watt as the cost of solar<u>.</u>
11. The Commission should adopt a five-year glide path as part of the successor tariff to minimize the cost shift, to ensure equity among all customers, and also to encourage the sustainable growth of the market, but not at the undue and burdensome financial expense of nonparticipant ratepayers.	
12. The Commission should address equity in the successor tariff through increased participation in low-income households and disadvantaged communities and combatting the cost shift.	
13. The Commission should adopt a successor tariff that addresses the cost shift to ensure equity but also to encourage adoption of electrification measures.	
14. The Commission should adopt SEIA/Vote Solar's proposal to allow customers to oversize their systems by 50 percent, while maintaining the current net surplus generation compensation rate, to promote electrification.	14. The Commission should adopt SEIA/Vote Solar's proposal to allow customers to oversize their systems by 50 percent<u> **based on the customer's prior year's usage**</u>, while maintaining the current net surplus generation compensation rate, to promote electrification<u>**, provided that *under all circumstances*, customers must expect to increase their usage to correspond with the system size within 12 months of interconnection, and execute an attestation to that effect**</u>.
15. The Commission should continue to encourage solar paired with storage in the successor tariff with both the benefits and costs in mind.	
16. Continuing to base retail export compensation rates on retail import rates does not comply with Public Utilities Code Section 2827.1.	
17. The Commission should base retail export compensation rates on values derived from the Avoided Cost Calculator.	
18. The Commission should not adopt the stepped-down retail rate glide path approach as it continues to use retail	

export compensation rates based on the retail import rate.	
19. The Commission should ensure customers can understand the retail export compensation rate structure to be able to make an informed decision on whether to purchase a solar system.	
20. The Commission should adopt the same retail export compensation rate structure for residential and nonresidential customer sectors.	
21. The Commission should adopt a successor tariff that requires residential customers to take service on an existing highly differentiated time-of-use rate available to all customers.	
22. AB 205 directs the Commission to authorize an income-graduated fixed charge for default residential customers by July 1, 2024.	
23. The Commission should not adopt a grid benefits charge as part of the successor tariff.	
24. The Commission should maintain the four charges adopted in D.16-01-044 as non-bypassable: public purpose program charge, nuclear decommissioning charge, the competition transition charge, and the Wildfire Fund Non-Bypassable Charge.	24. The Commission should ~~**maintain**~~ **expand** the four charges adopted in D.16-01-044 as non-bypassable **to include all non-bypassable charges enacted by the legislature since 2016 that do not expressly exempt NEM, including but not limited to**: ~~**public purpose program charge, nuclear decommissioning charge, the competition transition charge, and**~~ the Wildfire Fund Non-Bypassable Charge **and the Fixed Recovery Charge**. **Non-bypassable charges should be assessed on the same basis as non-NEM customer generators.**
25. The Commission should adopt a successor tariff that includes the ACC Plus as a glide path.	
26. The Commission should adopt no netting in the successor tariff.	The Commission adopt **actual metered imports and exports as the basis of billing** ~~**no netting**~~ in the successor tariff.
27. The Commission should maintain monthly billing and annual true-up	

periods for customers in the successor tariff.	
28. The Commission should set retail export compensation rates at monthly values for each hour, differentiated between weekday and weekend/holiday.	28. The Commission should set retail export compensation rates at monthly values for each hour~~**, differentiated between weekday and weekend/holiday**~~.
(**NEW**)	**<u>The ACC Plus adder should not be applied to net surplus generation at the annual true up.</u>**
29. The Commission should adopt Avoided Cost Calculator values based on a five-year schedule of values for each hour from the most recent Avoided Cost Calculator, adopted as of January 1 of the calendar year of the new successor tariff customer's interconnection date.	29. The Commission should adopt Avoided Cost Calculator values based on a **<u>levelized value based on</u>** a five-year schedule of values for each hour from the most recent Avoided Cost Calculator, adopted as of January 1 of the calendar year of the new successor tariff customer's interconnection date.
30. The Commission should require the utilities to average Avoided Cost Calculator values across climate zones within each of the utilities' service territory.	
31. The Commission should adopt a ratepayer-funded, stepped-down ACC Plus glide path that is available to all successor tariff customers who enroll in the tariff over the next five years.	31. The Commission should adopt a ratepayer-funded, stepped-down ACC Plus glide path that is available to ~~**all**~~ **<u>low-income</u>** successor tariff customers who enroll in the tariff over the next five years **<u>except for customers who are new construction customers required to install solar and customers who have transitioned to the successor tariff from a NEM tariff</u>**.
32. The Commission should permit customers to adopt critical peak pricing or peak day pricing as part of their highly differentiated time-of-use rates.	
33. The Commission should not adopt a requirement to apply credits only to charges during the same time-of-use period.	
34. The Commission should adopt the Net Billing tariff.	
35. The Commission should not maintain the NEM 2.0 tariff for	

low-income households.	
36. The Commission should adopt the same base successor tariff for all income levels.	
37. The Commission should not broaden the definition of low-income beyond CARE- and FERA-enrolled customers.	
38. The Commission should not decrease retail export compensation rate credits by applying the CARE and FERA discounts received by low-income households.	
39. The Commission should maintain the current structure of the low-income VNEM subtariffs until review of findings from the affordability proceeding and the SOMAH evaluation is conducted in this proceeding.	
40. The Commission should not require VNEM customers to enroll in highly differentiated time-of-use rates, but rather require these customers to take service on the time-of-use rates of their choice.	
41. The Commission should adopt the same net billing structure for the general VNEM and NEMA subtariffs, at this time.	
42. The Commission should maintain the netting intervals for general VNEM and NEMA subtariffs as they currently exist.	
43. The Commission should not provide an ACC Plus adder to VNEM subtariff customers.	44. The Commission should **~~not~~** provide an ACC Plus adder to **~~residential~~** VNEM subtariff customers.
44. The Commission should affirm that VNEM provides benefits to the grid similar to that of NEM 2.0.	
45. The Commission should maintain separate VNEM and NEMA subtariffs.	
(NEW)	**<u>New versions of VNEM and NEMA based on the Net Billing Tariff should be called NBTV and NBTA.</u>**
46. The Commission should allow multiple solar arrays on one property to be treated as one generator in the general	

VNEM subtariff.	
47. AB 2316 requires the Commission to evaluate community renewable energy programs.	
48. The Commission should not adopt a community solar tariff or subtariff in this decision.	
49. The Commission has the authority to amend previous decisions pursuant to Public Utilities Code Section 1708.	
50. The Commission has the authority to revise NEM 1.0 and NEM 2.0 tariffs.	
51. The Commission should not revise the NEM 1.0 or NEM 2.0 tariffs.	
(NEW)	<u>**The Commission should require NEM 1.0 and 2.0 customers to take service on a no-cost-shift tariff after their 20-year legacy period ends.**</u>
52. The Commission should define the interconnection application date as the submission date of an application that is free of major deficiencies and includes a complete application, a signed contract, a single-line diagram, a complete CSLB Solar Energy System Disclosure Document, a signed California Solar Consumer Protection Guide, and an oversizing attestation (if applicable).	
53. The Commission should adopt a sunset date as 120 days from the adoption date of this decision.	
54. The Commission should adopt the implementation of the successor tariff as described in Section 8.7 of this decision.	
55. The Commission should conduct an evaluation of the successor tariff.	
(NEW)	<u>**The Commission should report annually to the legislature and to all utility customers the cost shift from participating customers in NEM 1.0 and 2.0 and separately in the NBT.**</u>

Ordering Paragraphs	*Proposed Modification*
1. For the purposes of this decision, a low-income household is defined as residential customers enrolled in California Alternate Rates for Energy and the Family Electric Rates Assistance programs.	
2. A net billing tariff is adopted. Imports and exports will be calculated based on no netting of consumption and production and will be trued-up on an annual basis. Bill credits will be applicable toward import charges from any time of use time period. Net billing tariff customers shall comply with Electric Rule No. 21 Sections L.2-L.4 and Section L.7. for interconnecting to the electrical grid. Interconnection fees apply and remain as identified in Electric Rule 21. The net billing tariff shall contain the following adopted elements: (a) Retail Export Compensation Rates based on hourly Avoided Cost Calculator values averaged across days in a month, differentiated by weekdays and weekends/holidays. For the first five years of the successor tariff, *i.e.*, the glide path transition time, retail export compensation rates for residential net billing tariff customers will be based on a nine-year schedule of valuesfor each hour from the most recent Avoided Cost Calculator, adopted as of January 1 of the calendar year of the customer's interconnection date. For commercial customers, the Avoided Cost Calculator values	2. A net billing tariff is adopted. Imports and exports will be calculated based on no netting of consumption and production and will be trued-up on an annual basis. Bill credits will be applicable toward import charges from any time of use time period. Net billing tariff customers shall comply with Electric Rule No. 21 Sections L.2-L.4 and Section L.7. for interconnecting to the electrical grid. Interconnection fees apply and remain as identified in Electric Rule 21. The net billing tariff shall contain the following adopted elements: (a) Retail Export Compensation Rates based on hourly Avoided Cost Calculator values averaged across days in a month~~,~~ **~~differentiated by weekdays and weekends/holidays~~**. For the first five years of the successor tariff, *i.e.*, the glide path transition time, retail export compensation rates for residential net billing tariff customers will be based on **<u>the levelized values associated with</u>** a nine-year schedule of valuesfor each hour from the most recent Avoided Cost Calculator, adopted as of January 1 of the calendar year of the customer's interconnection date. For commercial customers, the Avoided Cost Calculator values

will be locked-in for five years. Following the locked in period, retail export compensation rates will be based on averaged hourly avoided cost values from the most recent Avoided Cost Calculator, adopted as of January 1. Tariff customers enrolling after the five-year glide path will not receive a lock-in period for Avoided Cost Calculator values. (b) An Avoided Cost Calculator Plus (ACC Plus) adder, based on a cents per kilowatt-hour exported. The ACC Plus will be available to net billing tariff customers during the first five years of the successor tariff, as a glidepath. The adopted ACC Plus adders, as indicated in the table below, will remain constant for a customer for nine years from the customer's interconnection date.	will be locked-in **and levelized over a** ~~**for**~~ five year~~s~~ **schedule**. Following the locked in period, retail export compensation rates will be based on averaged hourly avoided cost values from the most recent Avoided Cost Calculator, adopted as of January 1. Tariff customers enrolling after the five-year glide path will not receive a lock-in period for Avoided Cost Calculator values. (b) An Avoided Cost Calculator Plus (ACC Plus) adder, based on a cents per kilowatt-hour exported. The ACC Plus will be available to net billing tariff customers during the first five years of the successor tariff, as a glidepath. The adopted ACC Plus adders, as indicated in the table below, will remain constant for a customer for nine years from the customer's interconnection date. [Table] The adder will decrease by 20 percent annually, as measured by the first-year adder rate until the adder reaches zero. The adder will be a discrete line on the customer's utility bill, will apply to all charges, and will apply to future bills until the credit is used. Funding for the adder will be provided by all ratepayers through the Public Purpose Program **(PPP)** charge. **PPP rates will be trued-up on an annual basis through the IOUs' respective annual electric true-up advice**

	letter. Separately, the IOUs shall file a Tier 1 advice Letter within 30 days of the adoption of this decision to establish or modify an existing two-way balancing account to record and recover the ACC Plus adder. New construction customers who are required to install solar (per building code requirements) and customers who have transitioned to the Net Billing tariff from the NEM1 and NEM2 tariffs are not eligible to receive the ACC plus adder.

Adopted Avoided Cost Calculator Plus Adder			
Customer Segment	**PG&E**	**SDG&E**	**SCE**
Residential	$0.018/kWh	$0/kWh	$0.040/kWh
Low-Income	$0.087/kWh	$0/kWh	$0.093/kWh
Nonresidential	$0/kWh	$0/kWh	$0/kWh
(New Row) Residential Virtual	**$0.0475/kWh**	**$0.0448/kWh**	**$0.00350/kWh**

The adder will decrease by 20 percent annually, as measured by the first-year adder rate until the adder reaches zero. The adder will be a discrete line on the customer's utility bill, will apply to all charges, and will apply to future bills until the credit is used. Funding forthe adder will be provided by all ratepayers through the Public Purpose Program charge.

(c) Highly differentiated time-of-use rates as provided in thefollowing table. Additional eligible rates may be added by utility request through submittal of a Tier 3 advice letter or through its general rate case Phase 2 or rate design window. Net billing tariff customers may choose to enroll in critical peak pricing or peak day pricing rates.

Eligible Time Of Use Rates by Utility			
	PG&E	**SDG&E**	**SCE**
Eligible Rate	E-ELEC	EV-TOU-5	TOU-D-PRIME

(d) Low-income customers (as defined in this decision) may also participate in the net billing tariff. For such participants, the California Alternate Rates for Energy and Family Electric Rates Assistance discount will not beapplied to the retail export compensation rate.

(e) Customer sizing attestation requirements. Customers of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company who oversize their systems shall attest that they expect to increase their usage accordingly in the next year.	
(f) Four non-bypassable charges. The four charges are the public purpose program charge, nuclear decommissioning charge, competition transition charge, and the Wildfire Fund Non-Bypassable Charge.	(f) ~~Four~~ **<u>All statutory</u>** non-bypassable charges **<u>that do not expressly exempt NEM</u>**~~. The four charges are~~ **<u>including but not limited to</u>** the public purpose program charge, nuclear decommissioning charge, competition transition charge, ~~and~~ the Wildfire Fund Non-Bypassable Charge **<u>and the Fixed Recovery Charge</u>**. **<u>Non-bypassable charges shall be assessed on the same basis as non-NEM customer generators.</u>**
(g) Minimum bill or fixed charges. Net Billing tariff customers are subject to any minimum bill or fixed chargethat is contained in a customer's applicable rate.	
(h) True-up Dates. Customers taking service under the net billing tariff may make a one-time request that their annual true-up date be changed going forward.	
(i)	(i) **<u>Customers enrolled in the Net Billing Tariff are required to pay all incurred charges every month.</u>**
(j)	(j) **<u>The calculation for Net Surplus Compensation remains unchanged from NEM 2.0. To avoid double compensation for net exports, the IOUs shall determine if a customer has net exports at the end of their relevant period. If so, the IOUs shall charge the</u>**

	<u>customer for net exports at a per kWh rate equal to the applicable export compensation rate during the relevant period. The IOUs shall then credit the customer's annual net exports using the existing Net Surplus Compensation rate.</u>
3. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall notify net billing tariff customers within 24 hours of when their solar systems appear to be offline for a period of seven days or more.	**~~3. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall notify net billing tariff customers within 24 hours of when their solar systems appear to be offline for a period of seven days or more.~~**
<u>(NEW Ordering Paragraph)</u>	**<u>The adopted successor tariff elements will be available to the originally enrolled customer for a period of nine years from the interconnection date. Subsequent utility customers will not have a legacy period and will not be eligible for the export compensation lock in period or ACC+ except in the case where the subsequent customer is or was the legal partner of the original customer.</u>**
4. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Joint Utilities) shall work together to develop a standard oversizing attestation form for net billing tariff customers planning to oversize their systems for net billing. Joint Utilities shall make this available to net billing customers no later than 120 days from the adoption of thisdecision.	4. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Joint Utilities) shall work together to develop a standard oversizing attestation form for net billing tariff customers planning to oversize their systems **<u>up to 50 percent of their previous 12 months' usage</u>** for net billing. Joint Utilities shall make this available to net billing customers no later than 120 days from the adoption of this decision.
5. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Joint Utilities) shall work together to develop a standard process by which net billing tariff customers may request that	**~~Pacific Gas and Electric Company,~~** San Diego Gas & Electric Company**~~, and Southern California Edison Company (Joint Utilities)~~** shall **~~work together to~~** develop a **~~standard~~** process by which net billing tariff customers may request that their true-up date be changed. **~~Joint Utilities~~** **<u>San Diego Gas & Electric</u>** shall

their true-up date be changed. Joint Utilities shall make this available to net billing customers no later than 120 days from the adoption of this decision.	make this available to net billing customers no later than 120 days from the adoption of this decision.
6. Within 90 days of the adoption of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Joint Utilities) shall submit a Tier 3 advice letter that proposes adjustment factors calculated using the difference in each utility's residential stand-alone solar customers' net exports under no netting versus interval nettingin the last year. Joint Utilities shall update adjustment factors in a Tier 1 advice letter due annually thereafter.	
7. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall report on the number of new net billing tariff enrollments by customers enrolled in California Alternate Rates for Energy (CARE) and the Family Electric Rates Assistance (FERA) and the tenancy of those interconnected customers in the CARE and FERA programs. This documentation shall occur in the Joint Utilities' annual interconnection cost advice letters, which are currently filed in accordance with the directions in Decision 14-05-033 and Resolution E-4610. This advice letter shall now be known as the "Net Energy Metering and Net Billing Tariff Annual Reporting Advice Letter."	
8. Energy Division is authorized to conduct an evaluation of the net billing tariff adopted in Ordering Paragraph 3 above.	Energy Division is authorized to conduct an evaluation of the net billing tariff adopted in Ordering Paragraph ~~**3**~~ **2** above.

9. The Virtual Net Energy Metering subtariff for low-income eligible households shall remain unchanged until review in this proceeding of additional findings from Rulemaking 18-07-006 and the evaluation of the Solar on Multifamily Affordable Housing program.	The Virtual Net Energy Metering ~~**subtariff**~~ **tariffs** for low-income eligible households shall remain unchanged until review in this proceeding of additional findings from Rulemaking 18-07-006 and the evaluation of the Solar on Multifamily Affordable Housing program.
10. The Virtual Net Energy Metering (VNEM) general subtariff shall adhere to the same changes as the successor net energy metering tariff adopted in Ordering Paragraph 2 above, with two distinctions: VNEM subtariff customers shall take service on the time-of-use rates of their choice and netting intervals shall remain unchanged from the current net energy metering tariff. Further, the VNEM subtariff is revised to allow multiple solar arrays on one property to be treated as one generator, with credits allocated across the property.	The Virtual Net Energy Metering (VNEM) general **tariff** ~~**subtariff**~~**, renamed Net Billing Tariff Virtual (NBTV)** shall adhere to the same changes as the successor net energy metering tariff adopted in Ordering Paragraph 2 above, with ~~**two**~~ **one** distinction~~**s**~~: ~~**VNEM subtariff customers shall take service on the time-of-use rates of their choice and**~~ netting intervals shall remain unchanged from the current net energy metering tariff. Further, the VNEM **tariff** ~~**subtariff**~~ is revised to allow multiple solar arrays on one property **with separate points of interconnection** to be treated as one generator, with credits allocated across the property.
11. Within 90 days from the adoption of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall each submit a Tier 2 advice letter that updates each of their general market Virtual Net Metering tariffs to allow multiple solar arrays on one property to be treated as one generator for billing purposes, with credits allocated across the property.	
12. The Net Energy Metering Aggregation subtariff shall adhere to the same changes as the successor net energy metering tariff adopted in Ordering Paragraph 2 above with two distinctions: NEMA subtariff customers shall take service on the time-of-use rates of their choice and netting intervals shall remain	12. The Net Energy Metering Aggregation subtariff**, renamed Net Billing Tariff Aggregation (NBTA),** shall adhere to the same changes as the successor net energy metering tariff adopted in Ordering Paragraph 2 above with ~~**two**~~ **one** distinction~~**s**~~: ~~**NEMA subtariff customers shall take service on the time-of-use rates of their choice and**~~ netting intervals

unchanged from the current net energy metering tariff.	shall remain unchanged from the current net energy metering tariff.
13. Implementation of the changes adopted in the previous ordering paragraphs of this decision shall occur in the following steps:	
(a) Step 0: NEM 2.0 Sunset Period begins with adoption of this decision. Customers submitting a completed interconnection application prior to the end of the SunsetPeriod will be considered applicable for the current NEM 2.0 tariff.	(a) Step 0: NEM 2.0 Sunset Period begins with adoption of this decision. Customers submitting a completed interconnection application prior to the end of the Sunset Period will be considered applicable for the current NEM 2.0 tariff. **Joint Utilities are directed to pause transition of NEM 1.0 customers to NEM 2.0 until the commencement of Step 5.**
(b) Step 1: Within 30 days of the adoption of this decision Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Joint Utilities) shall each submit an information-only Tier 1 advice letter to provide the details of the net billing tariff, conforming to the elements adopted in Ordering Paragraph 3. Joint Utilities shall coordinate before submitting the advice letters to ensure language uniformity to the extent possible. Separately, Joint Utilities shall jointly file a Tier 1 advice letter within 30 days of the adoption of this decision requesting to establish a memorandum account to record costs for implementation of and marketing, education, and	(b) Step 1: Within ~~**30**~~ **45** days of the adoption of this decision Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Joint Utilities) shall each submit an information-only Tier 1 advice letter to provide the details **and rate factors** of the net billing tariff, conforming to the elements adopted in Ordering Paragraph 3. Joint Utilities shall coordinate before submitting the advice letters to ensure language uniformity to the extent possible. Separately, ~~**Joint Utilities shall jointly**~~ **PG&E, SCE, and SDG&E shall each** file a Tier 1 advice letter within 30 days of the adoption of this decision requesting to establish a memorandum account to record costs for implementation of and marketing, education, and outreach for the successor tariff~~**. The memorandum account should record utility costs for marketing, education, and outreach efforts described in Section 8.6.4**~~ and for the data collection, administrative support, and execution of the third-party evaluation outlined

	outreach for the successor tariff. The memorandum account should record utility costs for marketing, education, and outreach efforts described in Section 8.6.4 and for the data collection, administrative support, and execution of the third-party evaluation outlined in Section 8.8.	in Section 8.8. **The Joint Utilities may seek recovery of these incremental costs through a future GRC application.**
(c)	Step 2: Within 60 days of the effective date of this decision, Joint Utilities shall each submit a supplemental advice letter containing rate factors based on the applicable revenue and associated tariff sheets. Joint Utilities shall ensure language uniformity.	~~(c) **Step 2: Within 60 days of the effective date of this decision, Joint Utilities shall each submit a supplementaladvice letter containing rate factors based on the applicable revenue and associated tariff sheets. Joint Utilities shall ensure language uniformity.**~~
(d)	Step 3: Commission's Energy Division disposes of the advice letters from Step 1 and Step 2.	
(e)	Step 4. No later than 120 days after the effective date of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company will implement a tariff sunset on the prior net energy metering tariff, known as NEM 2.0, after which time, no additional customers will permitted to take service under the NEM 2.0 tariff. Any delay in Step 3 resulting in the disposition of a utility advice letter approved after 100 days from the effective date of this decision, will result in an equal, day-for-day, extension of time in the tariff sunset date. Customers with an	(e) Step 4. No later than 120 days after the effective date of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company will implement a tariff sunset on the prior net energy metering tariff, known as NEM 2.0, after which time, no additional customers will permitted to take service under the NEM 2.0 tariff. Any delay in Step 3 resulting in the disposition of a utility advice letter approved after 100 days from the effective date of this decision, will result in an equal, day-for-day, extension of time in the tariff sunset date. Customers with an interconnection application date after this sunset date will take service and be billed on the NEM 2.0 tariff and transitioned to the net billing tariff, once it is operationalized. The interconnection application date is defined as the submission date of a complete application

	interconnection application date after this sunset date will take service and be billed on the NEM 2.0 tariff and transitioned to the net billing tariff, once it is operationalized. The interconnection application date is defined as the submission date of an application that is free of major deficiencies and includes a complete application, a signed contract, a single-line diagram, a complete California Contractors State License Board Solar Energy System Disclosure Document, a signed California Solar Consumer Protection Guide, and an oversizing attestation (if applicable). Joint Utilities are directed to pause transition of NEM 1.0 customers to NEM 2.0 until the commencement of Step 5.	that is free of major deficiencies ~~and includes a complete application, a signed contract, a single-line diagram, a complete California Contractors State License Board Solar Energy System Disclosure Document, a signed California Solar Consumer Protection Guide, and an oversizing attestation (if applicable)~~. **A complete application includes: identification of customer point of interconnection; equipment specifications; a paid interconnection fee (if applicable); a signed interconnection agreement (if standard NEM); a single-line diagram; a complete California Contractors State License Board Solar Energy System Disclosure Document (if required); and a signed California Solar Consumer Protection Guide (if required). A final inspection clearance (signed building permit or electrical release) from the governmental authority having jurisdiction over the generating facility must be submitted within 1 year for facilities sized less than 30 kW and 2 years for facilities sized greater than 30 kW for NEM 2.0 eligibility to be maintained.** **Joint Utilities have the discretion to grant NEM 2.0 eligibility to projects that failed to submit a complete application by the sunset date due to utility-caused delays.** ~~**Joint Utilities are directed to pause transition of NEM 1.0 customers to NEM 2.0 until the commencement of Step**~~ 5.
(f)	Step 5: No later than 12 months following adoption ofthis decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall complete alignment of related	Step 5: No later than 12 months following adoption ofthis decision, ~~**Pacific Gas and Electric Company,**~~ San Diego Gas & Electric Company~~,~~ and Southern California Edison Company shall complete alignment of related necessary billing systems and transition to full implementation of the net billing tariff. **Pacific Gas and Electric Company shall implement**

necessary billing systems and transition to full implementation of the net billing tariff.	**the net billing tariff in two phases and shall complete its implementation no later than 18 months following adoption of this decision. Phase 1 shall implement the net billing tariff for standard residential solar and solar plus storage customers and shall be completed no later than 12 months following the adoption of this decision. Phase 2 shall implement the net billing tariff for non-residential and complex net billing schedules and sub-schedules such as virtual net billing, multiple technology net billing, and aggregated net billing for residential and non-residential customers. PG&E shall complete the Phase 2 implementation no later than 18 months following adoption of this decision.**
14. Rulemaking 20-08-020 remains open to address issue seven in the Scoping Memo and continuing matters related to this decision.	

ATTACHMENT B

Recommended Changes to Proposed Decision Spreadsheet Model

No	Tab	Cell Ref	Change
1	Avoided Costs	D8772:AH17531	Corrected error where SCE avoided costs were used in place of PG&E avoided costs
2	Dashboard	C32, C102	Change solar system sizing assumption to 90% of annual load and Res customer load to 12,000 kWh
3	Dashboard	C121, D121	Remove Non-CARE ACC+ for PG&E and SCE
4	Upfront Costs	H15	Change solar upfront capital cost to $2800/kW
5	Hourly Data	AC14:AD8773, AF14:AF8773	Changed formulas to set import and export to gross usage and gross solar+storage generation for VNEM customers. Also set "Net Metered Consumption" to gross usage for VNEM as it determines baseline credit amounts. =IF(Dashboard!$C$63,'Hourly Data'!W14,AA14-AB14*Dashboard!$C$64) =IF(Dashboard!$C$63,-'Hourly Data'!Z14,AB14*(1+Dashboard!$C$64)) =IF(Dashboard!$C$63,'Hourly Data'!W14,AC14+AD14)
6	Dashboard	C44, C46	Changed formulas to keep VNEM/NBTV on counterfactual rate per PD =IF(active_cust_config,C58,"NBT Rates") =IF(active_cust_config,C59,INDEX(Mapping!$C$4:Mapping!$E$6,MATCH(IF(active_cust_type="Residential",C44,"Commercial Existing TOU"),Mapping!$B$4:$B$6,0),MATCH(C13,Mapping!$C$3:$E$3,0)))
7	Dashboard	C124:E124	Added ACC+ values that achieve 9 year simple payback for VNEM/NBTV (PG&E: $0.0475, SCE: $0.0448, SDG&E: $0.035)